

2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal

Final Study

Chapter 5 – Revenue and Purchased Power Expense Forecast

SN-03-FS-BPA-01

June 2003



CHAPTER 5. REVENUE AND PURCHASED POWER EXPENSE FORECAST

This chapter describes the revenue and purchased power expense forecasts prepared for BPA's SN CRAC final rate proposal and the results of those forecasts.

5.1 Overview

The revenue and purchased power expense forecasts show BPA's expected levels of sales, revenues, purchases, and related expenses for the remainder of the current rate period — FY 2003-2006. BPA prepares two revenue forecasts: (1) one using current rates (*see* Table 5-1 at the end of this chapter), and (2) one using proposed rates (*see* Table 5-2). These revenue forecasts are used to demonstrate that BPA's proposed rates (with the use of the SN CRAC) satisfy BPA's revenue recovery. The revenue test is described in chapter 3 of this study, Revenue Recovery.

BPA's power rates placed into effect on October 1, 2001, as adjusted for the LB CRAC and the FB CRAC, are used in the calculation of revenues at current rates for FY 2003-2006. A projection of LB and FB CRAC percentage adjustments is used for future years. The proposed rates include the LB, FB, and the forecasted SN CRAC percentages multiplied by the base rates. However, for purposes of this study, the LB CRAC is applied separately, while (for the purpose of calculating revenues where appropriate) the FB and SN CRAC percentages are added together and applied to the base rates. The forecasted rates are applied to the loads subject to the SN CRAC for FY 2004-2006. Because the forecasted SN CRAC does not apply in FY 2003, revenues for FY 2003 are the same in both forecasts. The SN CRAC reduces the net monetary benefits received by the IOUs under their Residential Exchange Program settlement agreements. The SN CRAC also reduces the net cost of the power sales and the power buybacks under the IOUs' Residential Exchange Program settlement agreements. The SN CRAC also reduces

1 BPA's expenses under the LB CRAC for the Residential Load (RL) load reductions. The impact
2 on RL load reductions reduces both augmentation expenses and the rates subject to the LB
3 CRAC. BPA's revenue forecast also documents augmentation and other power purchases
4 because these purchases support power sales.

5 6 **5.2 Sources of BPA's Revenues**

7 PBL revenues are divided into five groups. The first (and largest) source of revenue is from the
8 sale of firm Subscription and pre-Subscription power to regional public agencies, Federal
9 agencies, IOUs, and DSIs. Priority Firm (PF) power sales to full requirements customers, partial
10 requirements customers, and PF block sales are all subject to the SN CRAC, but PF Slice sales,
11 pre-Subscription sales, PF TAC sales, and Irrigation Mitigation sales are not subject to the
12 SN CRAC. Industrial Firm (IP) power sales are subject to the SN CRAC, as are RL and PF
13 Exchange Subscription power sales to IOUs, RL load reductions, and IOU monetary benefits.

14
15 A second revenue source is long-term contractual power sale obligations where the rates are
16 already determined by contract or by contract formula outside of the Subscription or
17 pre-Subscription process. These include several contracts with IOUs, municipalities, public
18 agencies, and power marketers. These also include an extra-regional power sale to Bay Area
19 Rapid Transit (BART), which is subject to the SN CRAC because the price in that contract is
20 tied to the PF rate. No other long-term contractual obligation is subject to the SN CRAC.

21
22 A third major source of revenue is short-term energy sales where prices are determined in the
23 market. This includes power sold on a monthly, weekly, daily, or hourly basis. These sales are
24 not subject to the SN CRAC.

1 A fourth source of revenue is from the generation inputs for ancillary and reserve products. The
2 major component of this source is revenue from generation inputs provided to BPA's
3 Transmission Business Line (TBL). These revenues are not subject to the SN CRAC.

4
5 A final source of revenue is revenue credits from the U.S. Treasury and other miscellaneous
6 revenues. Treasury credits include: section 4(h)(10)(C) credits, Fish Cost Contingency Fund
7 (FCCF) credits, the Colville Settlement, downstream benefits credits from money paid to the
8 U.S. Army Corps of Engineers (Corps) and Bureau of Reclamation (Reclamation), revenues
9 from the sale of Green Tags, and the Slice true-up. Revenues from 4(h)(10)(C) and FCCF
10 credits were developed from runs of RiskMod and are documented in the documentation for
11 SN-03 Study, SN-03-FS-BPA-02, chapter 6. Other miscellaneous revenues include Energy
12 Efficiency, contract administration fees, late fees, and interest on late payments.

13 14 **5.2.1 Sales Subject to the SN CRAC**

15 **5.2.1.1 Priority Firm Power Sales.** All PF sales are subject to the SN CRAC with the
16 exception of PF Slice, sales to the Port of Seattle and Flathead Electric, and Irrigation Mitigation
17 sales. Non-Slice PF sales in FY 2002 were 4,040 average megawatts (aMW). They are expected
18 to be 3,910 aMW in FY 2003, and average 4,239 aMW during the FY 2004-2006 period. Of this
19 latter amount, 4,106 aMW are subject to the SN CRAC. As noted above, the non-Slice PF sales
20 that are not subject to the SN CRAC are the 71 aMW of sales to the Port of Seattle and to
21 Flathead Electric under the PF TAC, and 62 aMW of Irrigation Mitigation sales (actually FPS
22 sales that are grouped with PF sales). PF sales that are not subject to the SN CRAC also are not
23 subject to the FB CRAC. The revenues from the FB and SN CRACs are calculated and reported
24 together in the revenue forecast.

1 PF revenues are calculated in stages. First, the revenues from PF sales are calculated by
2 multiplying the appropriate May 2000 base rates (either stepped or flat) by one plus the
3 appropriate LB CRAC percentage, thereby determining the monthly HLH energy, LLH energy,
4 demand, and load variance charges. Those charges are applied to the projected HLH energy,
5 LLH energy, demand, and load variance billing quantities to obtain the corresponding monthly
6 revenue components. The Low Density Discount (LDD) is then calculated using the appropriate
7 discount percentage for each customer. Next, the Irrigation Mitigation revenues are added. The
8 FB and SN CRAC revenues are calculated by adding the FB and SN CRAC percentages
9 together, multiplying that sum by the appropriate May 2000 base rates, and multiplying the
10 resulting products (for HLH energy, LLH energy, demand, and load variance) by the
11 corresponding projected monthly billing quantities. Finally, the resulting revenues are summed
12 and then multiplied by one minus the LDD percentage for each customer, to obtain the FB and
13 SN CRAC revenues. These revenues were totaled and reported for each of the affected products:
14 full requirements, partial requirements, and block sales.

15
16 **5.2.1.2 Industrial Firm Power Sales.** Industrial Firm Power (IP) sales were 65 aMW in
17 FY 2002. These sales are projected to be 36 aMW in FY 2003, and are projected to average
18 83 aMW during the FY 2004-2006 period. All IP sales are subject to the SN CRAC. The
19 revenues from the FB and SN CRACs for IP sales are calculated and reported together. The IP
20 revenues were calculated by multiplying the May 2000 IP TAC (A) rate components by the
21 appropriate LB CRAC percentage, and then multiplying that product by the forecasted billing
22 quantities. The resulting amount represents the base revenues. The FB and SN CRAC revenues
23 are calculated by adding the FB and SN CRAC percentages together, multiplying that sum by the
24 appropriate IP rate components (*i.e.*, HLH energy, LLH energy, and demand), then multiplying
25 those amounts by the projected monthly IP billing quantities. The resulting revenues are the
26 FB and SN CRAC revenues. In the forecast of revenues at current rates that include the LB and

1 the FB CRAC (shown in Table 5-1) the process is exactly the same, except the SN CRAC
2 percentage is left out.

3
4 The last step in calculating IP revenues is to estimate take-or-pay damages. Take-or-pay
5 damages occur when IP purchases are curtailed and the power not purchased is sold in the
6 surplus market. There are take-or-pay damages if the sum of the projected monthly losses during
7 a fiscal year exceeds projected monthly gains from the sale of curtailed power deliveries at the
8 market rate. If there are take-or-pay damages and there is a high likelihood that they will meet
9 the revenue recognition criteria (*i.e.*, there is a high likelihood that they will be recovered during
10 the accounting period), the damages are reported as revenue in the year they are earned. In the
11 current revenue forecast, the IP rate adjusted for the LB and FB CRACs is less than the
12 forecasted market rate of power. Therefore, there are no take-or-pay damages forecast under the
13 current IP rate. In the proposed revenue forecast, the IP rate adjusted for the LB, FB, and
14 SN CRACs is higher than the forecasted market power rate in FY 2005 and 2006, although it is
15 still lower than the market rate in 2004, so there are take-or-pay damages forecast for these years
16 under the forecast of revenues at proposed rates.

17
18 **5.2.1.3 Residential Load.** RL power sales to IOUs were 350 aMW in FY 2002, of which BPA
19 bought back 120 aMW. Such sales are expected to be 382 aMW in FY 2003, of which BPA
20 bought back 127 aMW, and are expected to average 382 aMW during the FY 2004-2006 period,
21 of which BPA bought back 124 aMW. PacifiCorp and Puget Sound Energy (Puget) signed load
22 reduction agreements that total 618 aMW over the period FY 2004-2006. The load reduction
23 agreements require BPA to pay PacifiCorp and Puget for their portion of the original 1,000 aMW
24 of power sales not purchased. The cost is \$45.49 per MWh for all five years, but BPA agreed
25 with PacifiCorp and Puget that the utilities would agree to reduce the rate to \$38.00 per MWh if
26 litigation challenging their Subscription settlement agreements was settled. The difference in

1 these rates over five years is approximately \$200 million. PacifiCorp and Puget deferred
2 collection of the difference between \$45.49 and \$38.00 pending settlement discussions. Further
3 agreements with PacifiCorp and Puget have continued to defer this difference until at least April
4 of FY 2004. With implementation of an SN CRAC, load reduction payments to PacifiCorp and
5 Puget are reduced.

6
7 In the Residential Exchange Program settlement agreement, the IOUs received 900 aMW of
8 monetary benefits that are subject to the SN CRAC. IOU monetary benefits are reduced by the
9 product of the SN CRAC percentage and the lowest firm power rate (\$19.76/MWh), and that
10 adjusted rate is multiplied by 900 aMW and the hours in the year. In total, IOU loads affected by
11 the SN CRAC total 1,900 aMW over the period FY 2004-2006. The additional revenue from the
12 IOU power buybacks is also estimated to be the SN CRAC percentage multiplied by the RL flat
13 rate of \$19.76 per MWh, multiplied by the 124 aMW of IOU buybacks. This revenue is included
14 in the 382 aMW RL sales, while the expense associated with the buyback is kept at
15 \$38.00/MWh. The revenues from RL sales are calculated by multiplying the appropriate LB
16 CRAC percentage plus one by the appropriate RL rate components filed in May 2000 (*i.e.*, HLH
17 energy, LLH energy, and demand). The resulting adjusted rates are multiplied by the HLH
18 energy, LLH energy, and contract billing quantities. These revenues are added to the revenues
19 from the FB and SN CRACs.

20
21 There are two components of SN CRAC revenues from the IOUs. The first is RL power
22 deliveries including the sales associated with the power buybacks. The second is 900 aMW of
23 monetary benefits. FB CRAC revenues apply to the RL deliveries associated with sales and
24 power buybacks, but not to the monetary benefits.

1 The FB and SN CRAC revenues associated with RL power sales are calculated by adding the
2 FB and SN CRAC percentages together, multiplying that sum by the RL rate components filed in
3 May 2000, and multiplying that product by the forecasted RL billing quantities.

4
5 The SN CRAC revenues associated with the 900 aMW of monetary benefits are calculated by
6 multiplying the SN CRAC percentage by \$19.76 (the flat RL rate), and multiplying that product
7 by the 900 MW of monetary benefits. Both components make up the FB and SN CRAC
8 revenues associated with the RL rate. In the forecast of revenues at current rates shown on
9 Table 5-1 (without the SN CRAC), the SN CRAC is set equal to zero and there are no revenues
10 associated with RL power buybacks or IOU monetary benefits.

11
12 **5.2.1.4 Long-Term Power Sales.** The power sale to BART was 40 aMW in FY 2002. The
13 power sale is expected to be 38 aMW in FY 2003, and is expected to average 30 aMW during the
14 FY 2004-2006 period. The BART contract expires in FY 2006. The revenue from this contract
15 is calculated by multiplying the appropriate LB CRAC percentage plus one by the contract rate
16 components, and multiplying those adjusted rate components by the billing quantities. The
17 FB and SN CRAC revenue is calculated by adding the LB, FB, and SN CRAC percentages to
18 one, multiplying that sum by the BART contract rate components, and multiplying that rate by
19 the billing quantities. In the forecast of revenues at current rates shown in Table 5-1, the
20 SN CRAC percentage is set to zero.

21
22 In total, the SN CRAC is applied to 5,502 aMW of power deliveries, IOU power buybacks, and
23 monetary benefits.

24
25 **5.2.2 Power Sales Not Subject To SN CRAC.** Sales not subject to the SN CRAC include:
26 (1) pre-Subscription sales, which totaled 926 aMW in FY 2002, are expected to total 902 aMW

1 in FY 2003, and are expected to average 938 aMW during the period FY 2004-2006; (2) PF Slice
2 sales, which totaled 2,012 aMW in FY 2002, are expected to total 1,886 aMW in FY 2003, and
3 are expected to average 2,236 aMW during the period FY 2004-2006; (3) PF TAC sales made to
4 the Port of Seattle and Flathead Electric, which total 71 aMW during the period FY 2004-2006;
5 (4) Irrigation Mitigation sales averaging 62 aMW for FY 2004-06 made to full, partial
6 requirements, and block sales customers at the FPS rate but reported with PF full and partial
7 requirements sales; (5) most long-term contractual sales either inside or outside of the region,
8 which totaled 835 aMW in FY 2002, are expected to total 639 aMW in FY 2003, and are
9 expected to average 388 aMW over the FY 2004-2006 rate period, of which 358 aMW is exempt
10 from the SN CRAC; and (6) short-term power sales, which are expected to average 2,533 aMW
11 over the period FY 2004-2006. In total, the SN CRAC is not applied to 6,198 aMW of projected
12 power sales during the period FY 2004-2006.

13
14 **5.2.3 Other Revenues Not Subject To The SN CRAC.** Just as some sales are not subject to
15 the SN CRAC, none of the Treasury credits, revenues from ancillary and reserve product sales,
16 or miscellaneous revenues are subject to the SN CRAC. Treasury credits are primarily for that
17 portion of fish program expenses that are the responsibility of the non-power users of the
18 FCRPS. Fish Cost Contingency Fund (FCCF) credits were provided to BPA in the 1990s to
19 reimburse BPA for fish and wildlife expenses that should have been covered by non-power users
20 of the FCRPS. Most of the remaining FCCF credits (originally \$325 million) are expected to be
21 exhausted in FY 2003, with a small amount remaining for FY 2004-2006. There is a small and
22 continuing credit for payments to the Colville tribe and a similar small credit for payments to the
23 Corps and Reclamation from owners of downstream projects. Revenues from the sale of
24 ancillary and reserve products are not subject to the SN CRAC and are expected to remain
25 relatively constant at about \$84 million a year. Ancillary and reserve products and services are
26 described in more detail below (*see* section 5.4.8). Revenues from energy efficiency and

1 miscellaneous sources are projected to be about \$16 million per year, most of which is offset by
2 expenses of an equal magnitude.

4 **5.3 Load Forecasts**

5 The load forecasts used in BPA's revenue forecast are described in chapter 2 of this study and
6 are documented in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 2. Both
7 current and proposed rates are applied to these loads. The firm load forecast is discussed in the
8 testimony of Hirsch, *et al.*, SN-03-E-BPA-05. This includes pre-Subscription sales, all
9 categories of PF sales, IP sales, RL sales, and long-term contractual sales. The firm loads at
10 current rates are assumed to be the same as the firm loads at proposed rates for the purpose of
11 this rate proposal.

12
13 Because the forecast of firm loads is the same, the forecast of surplus power sales and revenue is
14 the same at both existing and proposed rates. The forecast of surplus sales and revenue is
15 described in chapters 4 and 6 of this study and in the testimony of Oliver, *et al.*,
16 SN-03-E-BPA-08. This assumption simplifies and minimizes the number of studies and
17 analyses needed for this proposal.

19 **5.4 Revenue Forecast Methodology**

20 **5.4.1 Revenues from Priority Firm Sales.** PF power sales are the largest source of FB and
21 SN CRAC revenue. Revenues from PF power sales are calculated by multiplying the
22 appropriate PF rates with the corresponding billing determinants (HLH energy, LLH energy,
23 Load Variance, and demand). The LDD is also incorporated as it applies to specific customers.
24 Loads and billing determinants were developed for each specific customer. The forecast of
25 revenues at current rates (Table 5-1) and the forecast of revenues at proposed rates (Table 5-2)
26 were based on those load forecasts, after increasing the rates by the appropriate LB CRAC

percentage that was forecasted to recover projected augmentation expenses. The FB and SN CRAC revenues are determined by adding the expected value of the FB and SN CRAC percentages together, multiplying that sum by the appropriate PF rate components, and multiplying those adjusted rates by the appropriate billing determinants. These revenues are reported by sales category on a monthly basis. *See* documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 5.

As mentioned above, FB and SN CRAC percentages do not apply to the PF TAC, PF Slice, or Irrigation Mitigation rates. Customers that chose a PF stepped-rate are charged a different rate than customers that chose a flat rate. There is no load variance charge for PF Block power. The billing determinants for the loads were developed on a customer-by-customer basis, but are reported in summary form. *See* documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 5.

Revenues from proposed rates were calculated in the same manner as revenues from current rates, except that the expected value of the SN CRAC percentage was added to the expected value of the FB CRAC percentage and applied to the applicable base rates. Consequently, there is an amount attributable just to the sum of the FB and SN CRACs. In the forecast of revenues at current rates, the FB CRAC percentage is equal to the maximum amount. Annual summaries of these revenues at both current and proposed rates can be found in Tables 5-1 and 5-2 at the end of this chapter, and monthly summaries, which show the FB and SN CRAC revenues, are contained in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 5.

5.4.2 Revenues from Sales to Investor-Owned Utilities. Power deliveries and monetary benefit agreements with the IOUs provide the second largest source of FB and SN CRAC revenues. The revenues from RL sales, including those associated with power buybacks, are determined by applying HLH energy, LLH energy, and demand charges, increased by the

1 projected LB CRAC percentage, to the corresponding contracted HLH energy usage, LLH
2 energy usage, and contract demand quantities. In the forecast of revenues at current rates in
3 Table 5-1, FB CRAC revenues are calculated by multiplying the FB CRAC percentage by the
4 base rates and multiplying that product by the appropriate billing determinants. In the forecast of
5 revenues at proposed rates, the FB and SN CRAC revenues are calculated by adding those
6 percentages together, multiplying that sum by the base rates, and multiplying those rates by the
7 appropriate billing determinants.

8
9 The revenue adjustment to the IOU monetary benefits was calculated by multiplying the
10 SN CRAC percentage by the flat RL rate (\$19.76/MWh), and multiplying that amount by the
11 total MWh associated with the 900 aMW of IOU monetary benefits for each month of the
12 FY 2004-2006 period. The resulting amounts were added to the RL revenues in the proposed
13 rate forecast.

14
15 The reduction in expenses associated with 618 aMW of IOU load reductions from PacifiCorp
16 and Puget is estimated by calculating the amount that the sum of the FB and SN CRAC
17 percentages from the base case in any month exceeds the maximum amount of FB percentage for
18 that month, multiplying that difference by \$19.76 (the lowest firm power rate), and multiplying
19 that adjusted rate by 618 aMW and the number of hours in the year. This is about \$16 million
20 per year. This amount was subtracted from BPA's augmentation expenses in the forecast of
21 revenues at proposed rates, then the LB CRAC percentages for FY 2004-2006 were reduced, and
22 the revenues recovered from the LB CRAC were reduced. That reduction in revenues subject to
23 the LB CRAC offsets the reduction in augmentation expenses. Annual summaries of RL sales
24 and revenues at both current and proposed rates can be found in the tables at the end of this
25 chapter. Monthly summaries showing the revenues from the changes in monetary benefits are
26 contained in the rate forecast in documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 5.

1 **5.4.3 Revenues from Sales to DSIs.** Revenues from DSIs are increased by the SN CRAC.

2 Sales made at the IP TAC (A) and IP TAC (B) rates are subject to the SN CRAC. DSI

3 customers may curtail their purchases from BPA, but those curtailments are subject to a

4 take-or-pay charge. Take-or-pay charges are based on the difference between the market price of

5 energy and the average price that could be received from sales at the applicable IP rate,

6 multiplied by the amount of energy curtailed during a particular period of time. For BPA's May

7 2000 Proposal, this forecast of revenues at current rates assumed that the market price of energy

8 is high enough relative to the IP rate that there is no exposure to take-or-pay charges. At the

9 proposed IP rate, take-or-pay charge obligations are likely to be incurred.

10
11 **5.4.4 Take-or-Pay Charges at Proposed Rates.** The forecast of revenues at proposed rates

12 assumes that BPA does not reflect any take-or-pay charges from Golden Northwest, Kaiser, or

13 Longview Aluminum because there is only a small likelihood that those damages are recoverable

14 during the FY 2004-2006 time period. This forecast further assumes that Columbia Falls

15 Aluminum will exercise its one-time contract option to reduce its IP purchases to a very low

16 level without a penalty, thereby avoiding take-or-pay charges. Annual summaries of these sales

17 and revenues at both current and proposed rates can be found in Tables 5-1 and 5-2 at the end of

18 this chapter. Monthly revenue summaries are contained in the documentation for SN-03 Study,

19 SN-03-FS-BPA-02, chapter 5.

20
21 **5.4.5 Revenues from pre-Subscription Sales.** Revenues from pre-Subscription sales and

22 long-term contracts were calculated on a contract-by-contract basis and summarized as a group

23 for the hub to which those customers are assigned, as reflected in the tables at the end of this

24 chapter. Currently, customers are assigned to one of three hubs: Bulk, East, and West. The

25 Bulk hub includes the IOUs, DSIs, extra-regional long-term contracts, and short-term sales. The

26 East and West hubs include public and Federal agency customers. Customers with

pre-Subscription contracts are assigned to either the East or the West hubs depending on location. Pre-Subscription contracts were signed prior to the May 2000 rate proposal and are not subject to the LB, FB, or SN CRACs, with the exception of BART. Annual summaries of these sales and revenues at both current and proposed rates can be found in the tables at the end of this chapter. Monthly summaries are contained in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 5.

5.4.6 Revenues from PF Slice Sales. Revenues from PF Slice sales were calculated using the Slice share associated with each participating customer. The Slice rate was adjusted for the forecasted LB CRAC percentage increase. Slice customers are subject to an annual true up instead of the FB or SN CRAC, and estimates of these annual true-ups are recorded separately in Tables 5-1 and 5-2 at the end of this chapter. The Slice true-ups are consistent with the forecast of BPA's expenses contained in this proposal. Revenues from Seasonal and Irrigation Mitigation sales are not subject to the LB, FB, or SN CRACs, as provided in the GRSPs.

5.4.7 Revenue from Secondary Energy Sales. Revenues from secondary energy sales are based on forecasted market supply and demand conditions. These sales include both committed and forecasted amounts. The committed sales are based on confirmation agreements, and the remaining secondary energy sales are a forecast of supply under various conditions and market prices. The development of the market price forecast and the short-term sales revenue forecast is described in chapter 4 of this study and in the testimony of Oliver, *et al.*, SN-03-E-BPA-08. The expected value sales, prices, and revenues represent a 50-year average and are documented in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 4.

5.4.8 Revenues from Ancillary and Reserve Product Sales. Revenues from ancillary and reserve product sales are estimated on a product-by-product basis and are summarized in the

1 tables at the end of this chapter. These revenues are derived almost entirely from TBL. BPA
2 sells several ancillary and reserve products, which are discussed below.

3
4 **5.4.8.1 Federal Remedial Action Scheme.** This is an annual charge that compensates PBL
5 for TBL's share of the annual cost of Generation Dropping for the AC Intertie. The total annual
6 cost, \$293,500 was established in PBL's 2002 power rate case. It was determined that TBL's
7 share of the total cost was \$231,470, and TBL is billed in 12 equal monthly amounts.

8
9 **5.4.8.2 Generation Supplied Reactive Power.** This is an annual charge PBL collects from
10 TBL to compensate for the reactive power and voltage control that FCRPS generation facilities
11 provide to the transmission system. In its 2002 power rate case, PBL identified FCRPS
12 generation-related components that are used in the production of both real and reactive power.
13 These components, referred to collectively as "electrical plant," are the generator stator and
14 rotor, exciters, voltage regulators, certain power plant equipment, step-up transformers, and
15 generation integration facilities. Also included is 50 percent of accessory electrical equipment.
16 Electrical plant is used to supply both real and reactive power. Therefore, some fraction of the
17 cost of electrical plant is allocated to the generation input for reactive power and voltage control.
18 PBL also allocated the cost of real power losses associated with the flow of reactive power in the
19 generation equipment to the generation input charge, as well as the costs associated with
20 synchronous condensing (both plant modifications and energy costs). PBL determined that the
21 total average annual cost to provide this generation input for Reactive Power and Voltage
22 Control was \$25 million.

23
24 **5.4.8.3 Station Service.** TBL obtains station service for many of its facilities directly off the
25 BPA transmission system. The power supplied directly off the BPA system is all supplied by
26 PBL. The purpose of this charge is to compensate PBL for the amount of station service being

1 directly supplied by PBL for use at BPA substations. There are very few locations on the BPA
2 system where station service usage is metered. Because of this, a methodology was developed in
3 PBL's 2002 rate case to estimate the amount of kWh usage for each BPA substation. This
4 methodology was based on the amount of primary station service transformation installed at each
5 substation location multiplied by a load factor associated with average substation service usage.
6 An overall average (weighted by transformer capacity) load factor of 904 percent was used for
7 calculating station service usage. The system station service usage was estimated to be
8 6,432,205 kWh/month, or an average of 8.8 aMW. PBL then applied a rate of 22.19 mills/kWh,
9 the average PF rate, to arrive at a total annual cost of \$1.7 million for station service.

10
11 **5.4.8.4 Regulating Reserves.** In its 2002 power rate case, PBL developed a methodology to
12 allocate the costs of the FCRPS to provide regulating reserves to the control area. Regulating
13 reserves are produced by the generation capacity of a power system that is immediately
14 responsive to Automatic Generation Control (AGC) signals without human intervention.
15 Regulating reserves are required to provide AGC response to load and generation fluctuations in
16 an effective manner. In order to maintain desired compliance with specific performance criteria,
17 PBL estimates TBL's share of the total control area requirement to be 149 aMW. The
18 established input cost for regulating reserves was determined to be \$6.50/kW-mo. This input
19 cost includes the costs of the 10 largest FCRPS hydro projects, plus an AGC adder to account for
20 lost efficiency and increased operation and maintenance costs due to the provision of this
21 service. Regulating reserves may be provided only by the ten largest plants and, therefore, the
22 cost of this service is based solely upon the costs of these plants. The costs of the largest
23 ten plants include a share of fish and wildlife costs and associated generation integration and
24 step-up transformer costs. The methodology excluded all other hydro assets, CGS,
25 non-performing assets, conservation, the Residential Exchange Program settlements, and the
26 costs associated with providing generation-supplied reactive and voltage control. The revenue

requirement associated with the regulating reserve generation input was calculated by taking TBL's share of the annual average regulating reserve requirement for the control area (149 aMW * 12 * 1,000), multiplied by \$6.50/kW-month, which equals forecasted annual revenues of \$11.5 million owed by TBL to PBL.

5.4.8.5 Operating Reserves. Operating reserves are the unloaded generating capacity, interruptible load, or other on-demand rights that the control area is able to fully deploy within ten minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to one hour. Operating reserves include both spinning reserves and supplemental operating reserves. The WECC Minimum Operating Reliability Criteria require that each control area maintain an operating reserve equal to at least 5 percent of all hydro and seven percent of all thermal and other non-hydro on-line generation within the control area. The per unit input cost for operating reserves was developed by calculating the unit cost of all FCRPS hydro projects, including fish and wildlife, generation integration, and step-up transformer costs. This methodology excludes the costs of CGS, non-performing assets, conservation, and the Residential Exchange Program settlements.

5.4.8.6 Spinning Reserves. Spinning reserves, a part of operating reserves, are the unloaded generating capacity of a system's firm resources that are synchronized to the power system and provide additional energy as required to be immediately responsive to system frequency. The WECC requires that each control area maintain spinning reserves equal to a minimum of 50 percent of its operating reserve obligation. The per-unit cost for spinning reserves was calculated to be \$5.63/kW-month. The revenue requirement associated with the spinning reserve generation input was calculated based on an annual average spinning reserve requirement for the control area of 263 aMW (263 aMW * 12 * 1,000), multiplied by \$5.63/kW-month, which equals forecasted annual revenues of \$17.5 million owed by TBL to the PBL.

1 **5.4.8.7 Supplemental Reserves.** In its 2002 power rate case, PBL developed the unit cost
2 associated with supplemental reserves. Supplemental reserves are that portion of the operating
3 reserves that do not meet the definition of spinning reserves. Generally, supplemental reserves
4 are that portion of operating reserves capable of serving load on a sustained basis within
5 ten minutes. The per-unit cost for supplemental reserves was calculated to be \$5.63/kW-month.
6 The revenue requirement associated with the supplemental reserve generation input was
7 calculated based on an annual average supplemental reserve requirement for the control area of
8 263 aMW (263 aMW * 12 * 1,000), multiplied by \$5.63/kW-month, which equals forecasted
9 annual revenues of \$17.5 million owed by TBL to PBL.

10
11 **5.4.8.8 Corps/Reclamation Network/Delivery Facilities.** This is a cost assigned to TBL for
12 transmission facilities owned by the Corps and Reclamation. The Corps and Reclamation own
13 transmission facilities associated with their respective generating projects. In its 2002 power rate
14 case, PBL included all the Corps and Reclamation costs in the generation revenue requirement,
15 including the costs functionalized to transmission. Then the Corps and Reclamation
16 transmission investment costs were identified and segmented so that the annual costs of the
17 transmission facilities were allocated to TBL. The total annual costs of these facilities assigned
18 to TBL are \$3.6 million in FY 2004-2005 and \$3.5 million in FY 2006.

19
20 **5.4.8.9 Reserve Services.** Reserve Services are forecasted sales of ancillary services to third
21 parties. The information used to create this forecast is deemed market sensitive and cannot be
22 shared, but reserve services amount to \$3.8 million per year paid by other parties to PBL.

23
24 **5.4.9 Energy Efficiency and Miscellaneous Revenues.** Revenues from the sale of Energy
25 Efficiency services are roughly equal to expenses for each year of the rate period. Energy
26 Efficiency revenues are forecasted to be \$9.3 million per year. Revenues from Green Tag sales

1 are projected to be less than \$0.8 million per year during the period FY 2004-2006.

2 Miscellaneous revenues are generally comprised of late fees, contract administration fees, and
3 interest for late bills, and are projected to be approximately \$3.4 million per year.

4
5 **5.4.10 Revenue Credits.** BPA receives several revenue credits each year. The Colville credit is
6 set by legislation at \$4.6 million per year. The Corps and Reclamation credits are based on an
7 estimate of receipts expected from owners of downstream projects. The FCCF credits are based
8 on remaining credits and an expected value analysis of water conditions. Because future water
9 years could be among the 15 worst years on record, these credits may be accessed until they are
10 exhausted. Almost all of the original \$325 million FCCF fund will be used by the end of
11 FY 2003. The 4(h)(10)(C) credits are equal to 22 percent of the operational and programmatic
12 expenses associated with fish and wildlife programs. The 22 percent figure is the non-power
13 share of the FCRPS fish and wildlife expenses for which BPA receives Treasury credits.

14
15 **5.4.11 Slice True-Up Adjustment Forecast.** The Slice True-Up Adjustment Charge is
16 calculated after final audited actual financial data is available for the fiscal year. BPA calculates,
17 or “trues-up,” the difference between the actual and forecasted expenses and credits of the Slice
18 Revenue Requirement. This difference is the basis for the Slice True-Up Adjustment Charge,
19 which is billed to Slice purchasers in the months following the end of a fiscal year. The Slice
20 True-Up Adjustment Charge may be positive, indicating a payment from the Slice purchaser, or
21 it may be negative, indicating a BPA credit back to the Slice purchaser. For purposes of the
22 SN CRAC proposal, the revenues anticipated to be collected from Slice purchasers through the
23 Slice True-Up Adjustment Charge were forecasted for the FY 2003-2006 period.

24
25 Revenues anticipated to be collected from Slice purchasers through the Slice True-Up
26 Adjustment Charge were forecasted using Table D, Slice Product Costing and True-Up Table,

1 2002 GRSPs, September 2001, at 132-133. Table D contains the May 2000 Proposal forecasts of
2 the amounts in the expense and credit line items comprising the Slice Revenue Requirement
3 upon which the Slice rate was based. The Slice True-Up Adjustment Charge is calculated based
4 on the difference between the expense and credit amounts forecasted in Table D and the actual
5 expense and credit amounts that are tallied in any given fiscal year. To develop a forecast of
6 what this difference will be in FY 2003-2006, BPA assumed the actual expense and credit
7 amounts would be equal to the expense and credit amounts used for the SN-03 Study,
8 SN-03-FS-BPA-01. BPA assumed that the revenues anticipated to be collected from Slice
9 purchasers through the Slice True-Up Adjustment Charge for FY 2003 would be accrued during
10 FY 2003, and the revenues collected through the Slice True-Up Adjustment Charge for FY 2004
11 would be accrued during FY 2004, and so on for the remainder of the rate period.

12
13 The Slice True-Up has some base assumptions that do not change to reflect actual events. One
14 key assumption in the development of the forecast of Slice True-Up revenues is that no Energy
15 Northwest bond refinancing activity was assumed for the FY 2003-2006 period. Therefore, for
16 purposes of the Slice True-Up Adjustment forecast, there is no difference assumed between the
17 Energy Northwest debt service expenses in the SN-03 Study, SN-03-FS-BPA-01, and the Energy
18 Northwest debt service expenses in the May 2000 Proposal.

19
20 Another key assumption is that the Minimum Net Required Revenues line item is assumed to be
21 zero. Therefore, for purposes of the Slice True-Up Adjustment forecast, there is no difference
22 assumed for this line item for FY 2003-2006.

23
24 The assumptions described above were made because of the uncertainty in forecasting these line
25 items and the volatility of their effects on the Slice True-Up Adjustment Charge.

The revenues anticipated to be collected through the Slice True-Up Adjustment Charge were calculated by multiplying the annual difference between the total forecasted Slice Revenue Requirement based on the SN-03 Study, SN-03-FS-BPA-01, expense forecast and the forecast of the Slice Revenue Requirement forecasted in the May 2000 Proposal by .226 (22.6 percent Slice sales), and adding about \$2 million each year in Slice Implementation Expenses. Slice Implementation Expenses are those expenses incurred by BPA to implement the Slice product. Slice purchasers are obligated to pay 100 percent of Slice Implementation Expenses.

The table below (Table 5-A) shows the components of the revenues anticipated to be collected through the Slice True-Up Adjustment Charge:

Table 5-A: Slice True-Up Revenues

Components of the Slice True-Up Revenues	FY 03	FY 04	FY 05	FY 06
Difference Between Total Forecasted Slice Revenue Requirement for SN CRAC Study and May 2000 Proposal Slice Revenue Requirement	+\$64 million	+\$221 million	+\$298 million	+\$290 million
22.6 percent paid by Slice purchasers	\$15 million	\$50 million	\$67 million	\$66 million
Slice Implementation Expenses	\$2 million	\$2 million	\$2 million	\$2 million
Revenues from True-Up Adjustment Charge	\$17 million	\$52 million	\$70 million	\$68 million

5.5 Augmentation and Other Power Purchases

5.5.1 Augmentation Purchases. Augmentation purchases include load reductions, power buybacks, and power purchases. There are four categories of load reductions included in the forecast: (1) PF load reductions; (2) RL load reductions; (3) IP load reductions; and (4) power

1 marketer load reductions. The average annual augmentation expense associated with load
2 reductions for the period FY 2004-2006 is \$286 million. The PF load reductions end in
3 FY 2003, but the other three types of load reductions continue through the rate period. Power
4 buyback contracts were signed with PF Block purchasers and with three IOUs. The power
5 buybacks with the publics expire in FY 2003, but the power buybacks with the IOUs extend
6 through the remainder of the rate period. The average cost of the IOU power buybacks over the
7 FY 2004-2006 period is \$41 million per year.

8
9 There are three categories of power purchases for augmentation: those signed prior to August 1,
10 2000, those signed after August 1, 2000, and renewable resources. While some renewable power
11 purchase expenses are included in augmentation, the cost of renewable power purchases is
12 included in the renewable program cost line item and not with the augmentation expense in the
13 forecast of revenues at current or at proposed rates. The average annual expense associated with
14 these augmentation purchases and power buybacks (excluding renewable resources) is
15 \$358 million. This is lower than the \$427 million in the initial proposal because of the contract
16 settlement and termination of power purchases from Enron and the inclusion of revenues from
17 the sale of put options that had been omitted earlier. All augmentation purchases are calculated
18 on a contract-by-contract basis and summarized (in a group) on an annual basis in the tables at
19 the end of this chapter. A monthly summary of all categories of augmentation purchases is
20 contained in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 5.

21
22 **5.5.2 Other Power Purchases.** Other power purchases can be divided into four groups:
23 (1) committed purchases; (2) balancing purchases (including a portion of the Enron contract
24 settlement expense); (3) Port of Seattle and Flathead Electric purchases; and (4) renewable
25 resource purchases for Slice customers. Committed purchases are those purchases for which
26 confirmation agreements have already been signed and which are reflected in the load and

1 resource balance. The average annual cost of currently committed purchases during the
2 FY 2004-2006 period is \$30 million. Balancing purchases are an expected value output of
3 RiskMod and are discussed in chapter 6 of this study and in the testimony of Conger, *et al.*,
4 SN-03-E-BPA-07. Balancing purchases are expected to average \$11 million per year over the
5 FY 2004-2006 period. Contracted power purchases for the Port of Seattle and Flathead Electric
6 average 54 aMW, at an average annual cost of \$25 million over the three-year period. This
7 amount includes expenses associated with the Enron settlement. This is down from the
8 \$28 million in the initial proposal because of the Enron settlement. These purchases are
9 identified separately from other committed purchases because they are entirely offset by
10 revenues from these customers. Renewable resource purchases for Slice customers are identified
11 but not reported with the other categories of power purchases because these costs are included
12 with other renewable program expenses.

13 14 **5.6 FY 2003 Revenue and Purchased Power Expenses**

15 Forecasted revenue and purchased power expenses for FY 2003 include a mix of actual revenues
16 through March and forecasted revenues for the remainder of the year. The actual revenues for
17 the months of April and beyond were not yet available when the FY 2003 forecast was prepared.
18 In that forecast, total FY 2003 revenue is projected to be \$3,108 million and purchased power
19 expenses are projected to total \$972 million.

20
21 **5.6.1 FY 2003 Revenues.** Revenue from Subscription sales, pre-Subscription sales, Slice
22 sales, and LB CRAC true-ups to public agencies totaled \$1,771 million, including the Slice
23 true-up, and reflects estimated deliveries (including Slice) of 6,698 aMW. Sales to regional
24 IOUs at the RL (and PF Exchange Subscription) rate are expected to result in FY 2003 revenues
25 of about \$95 million on sales of 382 aMW. Revenues from sales to DSIs (including take-or-pay
26 damages) are expected to be \$11 million on sales of 36 aMW. Revenues from short-term power

1 sales are projected to be about \$717 million on sales of 2,174 aMW. Revenues from ancillary
2 and reserve products are projected to total about \$84 million, of which almost \$81 million are
3 expected from TBL. Revenues from Energy Efficiency programs, Green Tag sales, and
4 miscellaneous sources are projected to total almost \$17 million, and Treasury credits (including
5 Corps and Reclamation and Colville credits) are projected to total \$193 million. All of these
6 revenues are documented in Table 5-1 at the end of this chapter and in monthly detail in the
7 documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 5.

8
9 **5.6.2 FY 2003 Purchased Power Expenses.** Load reduction augmentation expenses are
10 projected to total \$345 million in FY 2003, corresponding to load reductions of 1,437 aMW.
11 Augmentation power buyback expenses are projected to total \$60 million for buybacks totaling
12 159 aMW. Augmentation power purchase expenses, net of renewable resources for
13 augmentation, are expected to total \$378 million (including Enron settlement costs), for
14 purchases totaling 1,105 aMW. All of these expenses and quantities are documented in
15 Table 5-1 at the end of this chapter and in monthly detail in the documentation for SN-03 Study,
16 SN-03-FS-BPA-02, chapter 5.

17 18 **5.7 Revenues and Purchased Power Expenses for FY 2004-2006 at Current Rates**

19 Forecasted revenues at current rates (*i.e.*, without the SN CRAC) for the period FY 2004-2006
20 are shown in Table 5-1 at the end of this chapter. Revenues at current rates are projected to be
21 \$2,883 million in FY 2004, \$2,826 million in FY 2005, and \$2,813 million in FY 2006. Total
22 purchased power expenses are projected to be \$700 million in FY 2004, \$735 million in
23 FY 2005, and \$698 million in FY 2006.

24 25 **5.7.1 Revenues From Power Sales To Publics, IOUs, and DSIs at Current Rates.**

26 Revenues from firm power sales to regional public agencies are expected to increase from

1 \$1,723 million in FY 2004 to \$1,804 million in FY 2006, with sales growing from 7,366 aMW to
2 7,471 aMW over that same period. Revenues from the Slice true-up are projected to be
3 \$52 million in FY 2004, \$69 million in FY 2005, and \$68 million in FY 2006. Revenues from
4 firm power sales to IOUs at the RL and PF Exchange Subscription rates are projected to be about
5 \$93 million per year on sales of 382 aMW. Revenues from firm power sales to DSIs are
6 projected to average \$24 million per year from sales of 83 aMW per year over this 3-year period.

7
8 **5.7.2 Revenues From Long-Term Contractual Sales.** Revenues from long-term contracts
9 are projected to decline from \$158 million on sales of 441 aMW in FY 2004, to \$136 million on
10 sales of 390 aMW in FY 2005, to \$113 million on sales of 334 aMW in FY 2006. The single
11 largest contract is a capacity sale to PacifiCorp. There is no net energy sale associated with this
12 contract because energy delivered during HLH is returned during LLH.

13
14 **5.7.3 Revenues From Secondary Energy Sales.** Revenues from secondary energy sales are
15 the most volatile of BPA's revenues due to the uncertainty of supply and market prices. In
16 FY 2004, these revenues are projected to total \$663 million on sales of 2,625 aMW. In FY 2005,
17 short-term market sales revenues are projected to total \$537 million on sales of 2,542 aMW. In
18 FY 2006 these revenues are projected to total \$516 million on sales of 2,433 aMW. Revenues
19 from these sales are unaffected by the SN CRAC. The revenue forecast from short-term market
20 sales is a mix of committed and forecasted sales. The forecasted sales, prices, and revenue are
21 estimated using RiskMod, which is also used to estimate balancing purchases. These monthly
22 sales, prices, and revenue projections are documented in the documentation for SN-03 Study,
23 SN-03-FS-BPA-02, chapter 4, and discussed in the testimony of Oliver, *et al.*, SN-03-E-BPA-08.

24
25 **5.7.4 Revenues From Ancillary and Reserve Products and Services.** Revenues from
26 ancillary and reserve products and services are forecasted to be \$84 million per year during the

FY 2004-2006 period. Revenues from energy efficiency programs and miscellaneous sources are forecasted to be \$16 million per year during this entire period.

5.7.5 Revenues From Treasury Credits. Revenues from Treasury credits are forecasted to total \$86 million in FY 2004, \$77 million in FY 2005, and \$76 million in FY 2006.

Section 4(h)(10)(C) credits were the largest part of this and totaled \$70 million per year during the period.

5.7.6 Purchased Power Expenses at Current Rates. Purchased power expenses from load reductions are forecast to average \$286 million over the FY 2004-2006 period for load reductions averaging 821 aMW. Augmentation purchases and load buyback expenses are projected to average \$358 million for purchases averaging 1,016 aMW. Other power purchases (not related to augmentation) are projected to average \$67 million per year for purchases averaging 207 aMW.

5.8 Revenues and Purchased Power Expenses for FY 2004-2006 at Proposed Rates

Forecasted revenues at proposed rates (*i.e.*, with the SN CRAC) for the period FY 2004-2006 are shown in Table 5-2 at the end of this chapter. Revenues at proposed rates are projected to be \$3,025 million in FY 2004, \$3,002 million in FY 2005, and \$2,977 million in FY 2006. Total purchased power expenses are projected to be \$685 million in FY 2004, increasing to \$718 million in FY 2005, and declining to \$682 million in FY 2006.

5.8.1 Revenues From Sales to Publics, IOUs, and DSIs. Revenues from firm power sales to regional public agencies are expected to increase from \$1,821 million in FY 2004 to \$1,882 million in FY 2005, and to \$1,898 million in FY 2006, with sales growing from 7,366 aMW to 7,471 aMW over that same period. Revenues from the Slice true-up are projected

1 to be \$52 million in FY 2004, \$70 million in FY 2005, and \$68 million in FY 2006. Revenues
2 from firm power sales to IOUs at the RL and PF Exchange Subscription rates are projected to be
3 about \$124 million in FY 2004, \$128 million in FY 2005, and \$126 million in FY 2006 on sales
4 of 382 aMW per year. The significant increase in RL revenues from the current rate forecast is
5 due to increased rates for 382 aMW of sales and the additional revenues from the 900 aMW of
6 monetary benefits that resulted in an average of \$23.6 million in additional RL revenues.
7 Revenues from firm power sales to DSIs are projected to be \$10 million from projected sales of
8 31 aMW in FY 2004, \$51 million in FY 2005 from projected sales of 83 aMW, and \$63 million
9 from projected sales of 138 aMW in FY 2006, for an average of \$41 million over the 3-year
10 period. Of this total, an average of \$15 million is expected from take-or-pay charges for power
11 contracted for but not expected to be taken. This was discussed in more detail in section 5.4.4
12 above.

13
14 **5.8.2 Revenues From Long-Term Contracts.** Revenues from long-term contracts are
15 projected to decline from \$159 million on sales of 441 aMW in FY 2004, to \$137 million on
16 sales of 390 aMW in FY 2005, and decline further to \$114 million on sales of 334 aMW in
17 FY 2006. The single largest contract is a capacity sale to PacifiCorp. There is no net energy sale
18 associated with this contract because energy delivered during HLH is returned during LLH.
19 Revenue from one long-term contract, BART, is affected by the SN CRAC, because it is tied to
20 the PF rate.

21
22 **5.8.3 Revenues From Secondary Energy Sales.** Because BPA assumes firm loads are
23 unchanged by the SN CRAC, revenues from secondary energy sales are the same as the current
24 rate forecast. In FY 2004 these revenues are projected to total \$663 million on sales of
25 2,625 aMW. In FY 2005, short-term market sales revenues are projected to total \$537 million on
26 sales of 2,542 aMW. In FY 2006, this revenue is projected to total \$516 million on sales of

2,433 aMW. Revenues from these sales are unaffected by the SN CRAC. The revenue forecast for short-term market sales is a mix of committed and forecasted sales.

5.8.4 Revenues From Ancillary and Reserve Products and Services. Revenues from ancillary and reserve products and services are forecasted to be \$84 million per year during the FY 2004-2006 period. Revenues from energy efficiency programs and miscellaneous sources are forecasted to be \$16 million per year during this entire period. These revenues are the same as in the current rate forecast.

Revenues from Treasury credits are forecasted to total \$86 million in FY 2004, \$77 million in FY 2005, and \$76 million in FY 2006. Section 4(h)(10)(C) credits were the largest part of this and totaled \$70 million per year during the period. Revenues from Treasury credits are unaffected by the SN CRAC.

5.8.5 Purchased Power Expenses at Proposed Rates. Purchased power expenses from load reductions are forecast to average \$269 million over the FY 2004-2006 period for load reductions averaging 821 aMW. Purchased power expenses for load reductions are lower than in the forecast of revenues at current rates because the cost of the IOU load reductions is reduced as a result of the SN CRAC. A detailed explanation is provided in section 5.4.2 above.

Augmentation purchases and load buyback expenses, excluding renewables, are projected to average \$358 million for purchases averaging 1,016 aMW. Other power purchases, not related to augmentation or renewables, are projected to average \$67 million per year for purchases averaging 207 aMW.

Table 5-1 Revenues at Current Rates

Summary of Sales and Revenues at Current Rates

	FY2003		FY2004		FY2005		FY2006	
	(\$000)	aMW	(\$000)	aMW	(\$000)	aMW	(\$000)	aMW
WEST HUB								
PF Full Service	\$216,096	806	\$219,151	871	\$231,782	884	\$239,589	902
PF Partial Service	\$168,410	630	\$173,341	685	\$179,840	695	\$183,986	701
PF Block Sales	\$413,347	1,588	\$390,372	1,622	\$413,156	1,627	\$421,197	1,635
LBCRAC True-ups	\$555	0	\$0	0	\$0	0	\$0	0
PF SLICE	\$410,545	1,445	\$382,766	1,712	\$391,536	1,702	\$391,448	1,727
TOTAL WEST PF	\$1,208,953	4,470	\$1,165,631	4,891	\$1,216,313	4,908	\$1,236,220	4,966
Pre-Subscription	\$69,174	327	\$73,871	338	\$74,232	340	\$70,039	318
TOTAL WEST	\$1,278,128	4,797	\$1,239,502	5,229	\$1,290,545	5,248	\$1,306,259	5,284
EAST HUB								
PF Full Service	\$135,256	534	\$149,424	625	\$155,631	635	\$155,134	649
PF Partial Service	\$60,826	175	\$62,608	211	\$65,471	215	\$66,603	219
PF Block Sales	\$47,718	177	\$42,622	185	\$43,798	182	\$40,631	173
LBCRAC True-ups	\$198	0	\$0	0	\$0	0	\$0	0
PF SLICE	\$127,159	441	\$118,707	522	\$121,427	519	\$121,400	527
TOTAL EAST PF	\$371,157	1,326	\$373,361	1,543	\$386,328	1,551	\$383,768	1,568
Pre-Subscription	\$104,720	575	\$109,907	594	\$112,126	607	\$114,389	619
TOTAL EAST	\$475,878	1,902	\$483,267	2,137	\$498,454	2,158	\$498,157	2,187
BULK HUB								
DSI IP Sales	\$10,973	36	\$8,824	31	\$23,489	81	\$40,531	138
LBCRAC True-ups	(\$15)	0	\$0	0	\$0	0	\$0	0
DSI Liquidated Damages Est.	\$0	0	\$0	0	\$0	0	\$0	0
NW Long-Term contracts	\$85,561	120	\$72,695	114	\$64,552	114	\$64,552	114
SW Long-term contracts	\$135,565	519	\$85,361	327	\$71,689	276	\$48,661	220
Subscription Sales to IOUs (RL)	\$95,420	382	\$91,414	383	\$92,759	382	\$94,389	382
LBCRAC True-ups	(\$96)	0	\$0	0	\$0	0	\$0	0
Committed Trading Floor Sales	\$429,031	1,406	\$18,628	73	\$11,022	41	\$11,022	41
Balancing Trading Floor Sales	\$226,691	550	\$644,381	2,552	\$526,461	2,501	\$505,336	2,392
Flat and Other Trading Floor Sales	\$0	0	\$0	0	\$0	0	\$0	0
Real-time Sales	\$61,254	218	\$0	0	\$0	0	\$0	0
Other Delivery Obligations	\$0	596	\$0	673	\$0	672	\$0	672
TOTAL BULK	\$1,044,383	3,827	\$921,303	4,153	\$789,972	4,066	\$764,490	3,958
OTHER REVENUE								
Total Ancillary and Reserves	\$83,435	0	\$84,127	0	\$84,098	0	\$84,025	0
4(h)(10)(c) credit	\$104,566	0	\$77,034	0	\$67,459	0	\$66,350	0
FCCF credit	\$78,898	0	\$41	0	\$4	0	\$18	0
Colville settlement	\$4,600	0	\$4,600	0	\$4,600	0	\$4,600	0
Corps & Bureau Credits	\$4,715	0	\$4,700	0	\$4,700	0	\$4,700	0
Slice True-Up	\$16,781	0	\$52,118	0	\$69,534	0	\$67,689	0
Green Tags	\$1,236	0	\$787	0	\$764	0	\$754	0
EE, Property Sales & Misc.	\$12,464	0	\$12,670	0	\$12,670	0	\$12,670	0
Aluminum Hedging	\$3,771	0	\$3,000	0	\$3,000	0	\$3,000	0
Total Miscellaneous	\$310,467	0	\$239,078	0	\$246,830	0	\$243,806	0
TOTAL REVENUE	\$3,108,855	10,526	\$2,883,150	11,519	\$2,825,801	11,471	\$2,812,713	11,429
check against monthly totals	\$3,108,855	10,526	\$2,883,150	11,519	\$2,825,801	11,471	\$2,812,713	11,429
PF Buyback for SLICE & Block	\$18,086	32	\$0	0	\$0	0	\$0	0
PF Reduction Ld Following	\$9,251	22	\$0	0	\$0	0	\$0	0
RL Reduction	\$205,639	618	\$246,580	618	\$285,979	618	\$285,979	618
RL Buyback	\$41,940	127	\$41,390	124	\$41,277	124	\$41,277	124
IP Load Reduction	\$100,188	647	\$2,091	51	\$2,085	51	\$2,085	44
IP Load Curtailment	\$0	0	\$122,352	431	\$110,181	380	\$96,895	330
Marketer Load Reduction	\$29,632	150	\$11,421	75	\$12,518	169	\$9,253	218
Augmentation Power Purchases Pre 8/00	\$170,001	669	\$167,018	594	\$167,920	592	\$117,421	376
Augmentation Power Purchases Post 8/01	\$228,045	468	\$181,466	407	\$201,912	435	\$211,091	457
Total Augmentation Costs	\$802,782	1295	\$649,966	1125	\$711,692	1151	\$667,107	957
Augmentation without Renewables	\$783,084	1263	\$631,403	1082	\$673,766	1091	\$628,316	875
Committed T.F. Purchases	\$147,130	477	\$35,855	140	\$27,438	114	\$27,044	114
Purchase Power Options (Enron)	\$1,424		\$3,980		\$4,349		\$4,349	
Other committed Purchases (Elwah, etc.)								
Slice Renewables (included in Renewable Expenses)	\$4,836	12	\$5,545	15	\$11,322	26	\$11,369	26
Balancing Power Purchases	\$16,374	39	\$7,657	17	\$8,365	25	\$17,388	49
Port of Seattle/Flathead Sleeves	\$24,038	61	\$21,108	54	\$21,050	54	\$21,050	54
Total Other Purchases	\$193,802	589	\$74,145	226	\$72,523	218	\$81,199	243
Other Purchases without Renewables	\$188,966	577	\$68,600	211	\$61,201	192	\$69,830	217

Table 5-2 Revenues with Proposed SN CRAC included

Summary of Sales and Revenues									
	FY2003		FY2004		FY2005		FY2006		
	(\$000)	aMW	(\$000)	aMW	(\$000)	aMW	(\$000)	aMW	
WEST HUB									
PF Full Service	\$216,077	806	\$241,080	871	\$252,726	883	\$258,031	899	
PF Partial Service	\$168,343	630	\$191,547	687	\$197,108	697	\$199,420	704	
PF Block Sales	\$413,118	1,587	\$429,334	1,621	\$450,465	1,625	\$454,325	1,634	
LBCRAC True-ups	\$555	0	\$0	0	\$0	0	\$0	0	
PF SLICE	\$410,545	1,445	\$380,573	1,712	\$386,265	1,702	\$387,252	1,727	
TOTAL WEST PF	\$1,208,638	4,469	\$1,242,534	4,890	\$1,286,564	4,906	\$1,299,029	4,964	
Pre-Subscription	\$69,039	326	\$73,446	336	\$73,767	338	\$69,519	315	
TOTAL WEST	\$1,277,677	4,795	\$1,315,980	5,226	\$1,360,331	5,244	\$1,368,547	5,279	
EAST HUB									
PF Full Service	\$135,256	534	\$163,982	625	\$171,442	635	\$175,790	649	
PF Partial Service	\$60,826	175	\$66,731	211	\$70,162	215	\$72,903	219	
PF Block Sales	\$47,718	177	\$46,727	185	\$48,193	182	\$45,969	173	
LBCRAC True-ups	\$198	0	\$0	0	\$0	0	\$0	0	
PF SLICE	\$127,159	441	\$117,464	522	\$119,792	519	\$120,099	527	
TOTAL EAST PF	\$371,157	1,326	\$394,904	1,543	\$409,590	1,551	\$414,761	1,568	
Pre-Subscription	\$104,720	575	\$109,907	594	\$112,126	607	\$114,389	619	
TOTAL EAST	\$475,878	1,902	\$504,810	2,137	\$521,715	2,158	\$529,150	2,187	
BULK HUB									
DSI IP Sales	\$10,973	36	\$9,674	31	\$25,657	81	\$43,794	138	
LBCRAC True-ups	(\$15)	0	\$0	0	\$0	0	\$0	0	
DSI Liquidated Damages Est.	\$0	0	\$0	0	\$25,136	0	\$18,912	0	
NW Long-Term contracts	\$85,561	120	\$72,695	114	\$64,552	114	\$64,552	114	
SW Long-term contracts	\$135,565	519	\$86,444	327	\$72,749	276	\$49,304	220	
Subscription Sales to IOUs (RL)	\$95,420	382	\$123,601	383	\$127,908	382	\$126,473	382	
LBCRAC True-ups	(\$96)	0	\$0	0	\$0	0	\$0	0	
Committed Trading Floor Sales	\$429,031	1,406	\$18,628	73	\$11,022	41	\$11,022	41	
Balancing Trading Floor Sales	\$226,691	550	\$644,381	2,552	\$526,461	2,501	\$505,336	2,392	
Flat and Other Trading Floor Sales	\$0	0	\$0	0	\$0	0	\$0	0	
Real-time Sales	\$61,254	218	\$0	0	\$0	0	\$0	0	
Other Delivery Obligations	\$0	596	\$0	673	\$0	672	\$0	672	
TOTAL BULK	\$1,044,383	3,827	\$955,423	4,153	\$853,485	4,066	\$819,393	3,958	
OTHER REVENUE									
Total Ancillary and Reserves	\$83,435	0	\$84,127	0	\$84,098	0	\$84,025	0	
4(h)(10)(c) credit	\$104,566	0	\$77,034	0	\$67,459	0	\$66,350	0	
FCCF credit	\$78,898	0	\$41	0	\$4	0	\$18	0	
Colville settlement	\$4,600	0	\$4,600	0	\$4,600	0	\$4,600	0	
Corps & Bureau Credits	\$4,715	0	\$4,700	0	\$4,700	0	\$4,700	0	
Slice True-Up	\$16,781	0	\$52,118	0	\$69,534	0	\$67,689	0	
Green Tags	\$1,236	0	\$787	0	\$764	0	\$754	0	
EE, Property Sales & Misc.	\$12,464	0	\$12,670	0	\$12,670	0	\$12,670	0	
Aluminum Hedging	\$3,771	0	\$3,000	0	\$3,000	0	\$3,000	0	
Total Miscellaneous	\$310,467	0	\$239,078	0	\$246,830	0	\$243,806	0	
TOTAL REVENUE	\$3,108,405	10,524	\$3,015,291	11,516	\$2,982,360	11,468	\$2,960,897	11,424	
check against monthly totals	\$3,108,405	10,524	\$3,015,291	11,516	\$2,982,360	11,468	\$2,960,897	11,424	
PF Buyback for SLICE & Block	\$18,086	32	\$0	0	\$0	0	\$0	0	
PF Reduction Ld Following	\$8,817	22	\$0	0	\$0	0	\$0	0	
RL Reduction	\$205,639	618	\$230,502	618	\$267,789	618	\$269,178	618	
RL Buyback	\$41,940	127	\$41,390	124	\$41,277	124	\$41,277	124	
IP Load Reduction	\$100,188	647	\$2,091	51	\$2,085	51	\$2,085	44	
IP Load Curtailment	\$0	0	\$134,077	431	\$120,327	380	\$104,673	330	
Marketer Load Reduction	\$29,632	150	\$11,421	75	\$12,518	169	\$9,253	218	
Augmentation Power Purchases Pre 8/00	\$170,001	669	\$167,018	594	\$167,920	592	\$117,421	376	
Augmentation Power Purchases Post 8/01	\$228,045	468	\$181,466	407	\$201,912	435	\$211,091	457	
Total Augmentation Costs	\$802,348	1295	\$633,888	1125	\$693,502	1151	\$650,305	957	
Augmentation without Renewables	\$782,650	1263	\$615,325	1082	\$655,576	1091	\$611,515	875	
Committed T.F. Purchases	\$147,130	477	\$35,855	140	\$27,438	114	\$27,044	114	
Purchase Power Options (Enron)	\$1,424		\$3,980		\$4,349		\$4,349		
Other committed Purchases (Elwah, etc.)									
Slice Renewables (included in Renewable Expenses)	\$4,836	12	\$5,545	15	\$11,322	26	\$11,369	26	
Balancing Power Purchases	\$16,374	39	\$7,657	17	\$8,365	25	\$17,388	49	
Port of Seattle/Flathead Sleeves	\$24,038	61	\$21,108	54	\$21,050	54	\$21,050	54	
Total Other Purchases	\$193,802	589	\$74,145	226	\$72,523	218	\$81,199	243	
Other Purchases without Renewables	\$188,966	577	\$68,600	211	\$61,201	192	\$69,830	217	